New Source Performance Standards (NSPS):

(a) The requirements of the Emissions Guidelines and Compliance Times for Sulfuric Acid Production Units, 40 CFR 60, Subpart Cd and 326 IAC 12, are not included in the permit for the sulfur recovery units, because the units are not existing sulfuric acid production units as defined at 40 CFR 60.81(a). Pursuant to 40 CFR 60.81(a), *Sulfuric acid production unit* means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(b) The requirements of the Standards of Performance for Fossil-Fuel-Fired Steam Generators, 40 CFR 60, Subpart D and 326 IAC 12, are not included in the permit for the units listed in the table below for the reasons shown in the table.

Unit	Reason Not Subject
EU-1007	Not a steam generating unit as defined at 40 CFR 60.41
EU-2001	Not a steam generating unit as defined at 40 CFR 60.41
EU-2002	Not a steam generating unit as defined at 40 CFR 60.41
EU-2003	Not a steam generating unit as defined at 40 CFR 60.41
EU-2004	Not a steam generating unit as defined at 40 CFR 60.41
A-602A burner	Acid gas burned in the unit is not fossil fuel as defined at 40 CFR 60.41, the gas is not derived from natural gas, petroleum, or coal for the purpose of creating useful heat.
A-602B burner	Acid gas burned in the unit is not fossil fuel as defined at 40 CFR 60.41, the gas is not derived from natural gas, petroleum, or coal for the purpose of creating useful heat.
HP Flare	Not a steam generating unit as defined at 40 CFR 60.41
LP Flare	Not a steam generating unit as defined at 40 CFR 60.41
Sulfur Block Flare	Not a steam generating unit as defined at 40 CFR 60.41
Loading Flare	Not a steam generating unit as defined at 40 CFR 60.41
EU-6000	Heat input capacity less than 250 MMBtu/hr
EU-7003	Block 2000 fractionator overhead supplied to the unit is not fossil fuel as defined at 40 CFR 60.41, the gas is not derived from natural gas, petroleum, or coal for the purpose of creating useful heat.
EU-7004	Block 2000 fractionator overhead supplied to the unit is not fossil fuel as defined at 40 CFR 60.41, the gas is not derived from natural gas, petroleum, or coal for the purpose of creating useful heat.

(c) The requirements of the Standards of Performance for Electric Utility Steam Generating Units, 40 CFR 60, Subpart Da and 326 IAC 12, are not included in the permit for the EU-3000 burners and waste heat boilers, package boiler EU-6000, and Block 7000 reformers and heat recovery boilers, because the units are not electric utility steam generating units as defined at 40 CFR 60.41Da. The units do not supply more than one-third of their potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

(d) 40 CFR 60, Subpart Db

(1) The requirements of the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for the units listed in the table below for the reasons shown in the table.

Unit	Reason Not Subject
EU-1007	Not a steam generating unit as defined at 40 CFR 60.41b
EU-2001	Process heater as defined at 40 CFR 60.41b
EU-2002	Heat input capacity less than 100 MMBtu/hr and a process heater as defined at 40 CFR 60.41b
EU-2003	Heat input capacity less than 100 MMBtu/hr
A-602A burner	Process heater as defined at 40 CFR 60.41b
A-602B burner	Process heater as defined at 40 CFR 60.41b
HP Flare	Not a steam generating unit as defined at 40 CFR 60.41b
LP Flare	Not a steam generating unit as defined at 40 CFR 60.41b
Sulfur Block Flare	Not a steam generating unit as defined at 40 CFR 60.41b
Loading Flare	Not a steam generating unit as defined at 40 CFR 60.41b
EU-6000	Heat input capacity less than 100 MMBtu/hr
EU-7003	Process heater as defined at 40 CFR 60.41b
EU-7004	Process heater as defined at 40 CFR 60.41b

(2) The fractionator heater, EU-2004, is subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, because it is a steam generating unit as defined at 40 CFR 60.41b for which construction commenced after June 9, 1989 that has a maximum design heat input capacity of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)). The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired indirect fractionator heater discharging to the fractionator tower, identified as EU-2004, approved in 2018 for construction, with a maximum heat input capacity of 156 MMBtu/hr, using no add on controls and exhausting to stack EU-2004.
  Note: EU-2004 is not a process heater as defined at 40 CFR 60.41b. The unit is not a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. The unit heats material for an equilibrium stage-type separation process.

Fractionator heater EU-2004 is subject to the following portions of Subpart Db.

(A) 40 CFR 60.40b(a)
(B) 40 CFR 60.40b(c)
(C) 40 CFR 60.40b(g)
(D) 40 CFR 60.40b(j)
(E) 40 CFR 60.41b
(F) 40 CFR 60.44b(a)(1)
(G) 40 CFR 63.44b(c)
(H) 40 CFR 63.44b(e)
(I) 40 CFR 60.44b(f)
(J) 40 CFR 60.44b(h)
(K) 40 CFR 60.44b(i)
(L) 40 CFR 60.46b(a)
(M) 40 CFR 60.46b(c)
(N) 40 CFR 60.46b(e)
(O) 40 CFR 60.48b(b)
(P) 40 CFR 60.48b(c)

(Q) 40 CFR 60.48b(d)
(R) 40 CFR 60.48b(e)(2)
(S) 40 CFR 60.48b(f)
(T) 40 CFR 60.49b

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to fractionator heater EU-2004 except as otherwise specified in 40 CFR 60, Subpart Db.

(e) 40 CFR 60, Subpart Dc

(1) The requirements of the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, are not included in the permit for the units listed in the table below for the reasons shown in the table.

Unit	Reason Not Subject
EU-1007	Not a steam generating unit as defined at 40 CFR 60.41c
EU-2001	Heat input capacity greater than 100 MMBtu/hr and a process heater as defined at 40 CFR 60.41c
EU-2002	Process heater as defined at 40 CFR 60.41c
EU-2003	Heat input capacity less than 10 MMBtu/hr
EU-2004	Heat input capacity greater than 100 MMBtu/hr
A-602A burner	Heat input capacity greater than 100 MMBtu/hr
A-602B burner	Heat input capacity greater than 100 MMBtu/hr
HP Flare	Not a steam generating unit as defined at 40 CFR 60.41c
LP Flare	Not a steam generating unit as defined at 40 CFR 60.41c
Sulfur Block Flare	Not a steam generating unit as defined at 40 CFR 60.41c
Loading Flare	Not a steam generating unit as defined at 40 CFR 60.41c
EU-7003	Heat input capacity greater than 100 MMBtu/hr
EU-7004	Heat input capacity greater than 100 MMBtu/hr

(2) The package boiler, EU-6000, is subject to the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, because it is a steam generating unit as defined at 40 CFR 60.41c for which construction commenced after June 9, 1989 that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h). The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, with a maximum heat input capacity of 68.50 MMBtu/hr, using no add-on controls and exhausting to stack EU-6000.

Boiler EU-6000 is subject to the following portions of Subpart Dc.

(A) 40 CFR 60.40c(a)
(B) 40 CFR 60.40c(b)
(C) 40 CFR 60.40c(h)
(D) 40 CFR 60.41c

(E) 40 CFR 60.48c

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to boiler EU-6000 except as otherwise specified in 40 CFR 60, Subpart Dc.

(f) The requirements of the Standards of Performance for Sulfuric Acid Plants, 40 CFR 60, Subpart H and 326 IAC 12, are not included in the permit for the sulfur recovery units, because the units are not sulfuric acid production units as defined at 40 CFR 60.81(a).

(g) The requirements of the Standards of Performance for Petroleum Refineries, 40 CFR 60, Subpart J and 326 IAC 12, are not included in the permit for the flares, fuel gas combustion units, and Claus sulfur recovery plant units listed in paragraph (h), because the units commenced construction after May 14, 2007

(h) This source is subject to the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60, Subpart Ja and 326 IAC 12, because the source is a facility engaged in producing distillate fuel oils or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. As defined at 40 CFR 60.101a, *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

According to an applicability determination by U.S. EPA (U.S. EPA Applicability Determination Index control number J015, Mr. Edward Reich, Division of Stationary Source Enforcement, EPA to Mr. Jim Snydor, Region 3, EPA, March 19, 1980) Subpart J was applicable to processes for converting coal to hydrocarbon liquids:

> "... The SRC II process generally utilizes a more typical refining process with the final product a liquid. This product would fall under the definition of petroleum in 60.101(b). Therefore, if any of the affected facilities mentioned in section 60.100(a) are used in this process, the NSPS for petroleum refineries would be applicable. ..."

SRC II was one of a number of direct coal liquefaction processes, including the Kohleoel process developed jointly by Ruhrkohle and VEBA. All are applications of the process invented by Friedrich Bergius in 1913 (ref: S. Vasireddy, et al., "Clean Liquid Fuels from Direct Coal Liquefaction: Chemistry, Catalysis, Technological Status and Challenges", Energy & Environmental Science, 2011(4), February 311-345; see also: <u>Technology Status Report 010 - Coal Liquefaction</u>, Department of Trade and Industry, London, October 1999).

The liquid phase hydrocracking (LPH) operation, gas phase hydrotreating (GPH) operation, and hydrogen production plant are not affected facilities under this subpart. These operations are not fluid catalytic cracking units (FCCU), fluid coking units (FCU), or delayed coking units. These operations are not described by the following definitions from 40 CFR 60.101a:

> *Delayed coking unit* means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors.
>
> *Fluid catalytic cracking* unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits.

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system.

LPH is a hydrogen cracking reaction, not thermal cracking, and the LPH process does not regenerate a catalyst. The GPH operation includes hydrocracking stages, which are, like the LPH process, not thermal cracking and do not regenerate catalysts.

The hydrogen plant is not a fuel combustion unit as defined at 40 CFR 60.101a. Natural gas and fractionator overhead are supplied to the hydrogen plant as feed for a catalytic reaction to produce gaseous hydrogen used in other operations and carbon monoxide, with additional hydrogen produced from carbon monoxide by the water gas reaction. The reactions in the hydrogen plant are thus a process that creates a product rather than the combustion of a fuel to generate heat.

The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired heater, identified as EU-1007, approved in 2018 for construction, with a maximum heat input capacity of 55.8 MMBtu/hr, with emissions discharging to the Coal Dryer.
- One (1) natural gas and process fuel gas-fired indirect feed heater discharging to the 1st stage reactors, identified as EU-2001, approved in 2018 for construction, with a maximum heat input capacity of 128.4 MMBtu/hr, using no add-on controls and exhausting to stack EU-2001.
- One (1) natural gas and process fuel gas-fired indirect treat gas heater receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, identified as EU-2002, approved in 2018 for construction, with a maximum heat input capacity of 52.8 MMBtu/hr, using no add-on controls and exhausting to stack EU-2002
- One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater discharging to the vacuum distillation tower, identified as EU-2003, approved in 2018 for construction, with a maximum heat input capacity of 9 MMBtu/hr, using no add on controls and exhausting to stack EU-2003
- One (1) natural gas and process fuel gas-fired indirect fractionator heater discharging to the fractionator tower, identified as EU-2004, approved in 2018 for construction, with a maximum heat input capacity of 156 MMBtu/hr, using no add on controls and exhausting to stack EU-2004.
- One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

  (1) One (1) two-stage high pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, identified as HP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  (2) One (1) two-stage low pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, identified as LP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

  (1) Amine Regeneration Unit, consisting of:

  (A) One (1) heat exchanger where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  (B) One (1) stripper column discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger or the reboiler and vapor to the overheads condenser, identified as Stripper, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  (C) One (1) water-cooled condenser discharging condensate to the stripper condenser accumulator, identified as Overheads Condenser, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  (D) One (1) accumulator drum discharging condensate to stripper reflux or the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, identified as Stripper Condenser Accumulator, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  (E) One (1) steam-heated reboiler discharging lean amine to the stripper reflux, identified as Stripper Reboiler, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  (2) Sour Water Stripping System, consisting of:

  (A) One (1) sour water stripping system receiving sour water from the Block 2000 vacuum distillation column, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

  (B) One (1) sour water stripping system receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

  (3) Sulfur Recovery System, consisting of:

  (A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602A burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602A Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605A, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUA

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602B burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602B Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605B, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUB

- Flares, as follows:

  (A) One (1) flare servicing overpressure and emergency reliefs from Block 2000, identified as High Pressure (HP) Flare, approved in 2018 for construction.

  (B) One (1) flare servicing overpressure reliefs from Block 7000, identified as Low Pressure (LP) Flare, approved in 2018 for construction.

  (C) One (1) flare servicing overpressure reliefs from Block 3000 and sulfur loading, identified as Sulfur Block Flare, approved in 2018 for construction.

  (D) One (1) flare servicing Block 4000 naphtha, diesel, and ammonia loading operations, identified as Loading Flare, approved in 2018 for construction.

- One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, with a maximum heat input capacity of 68.50 MMBtu/hr, using no add-on controls and exhausting to stack EU-6000.

This source is subject to the following portions of Subpart Ja.

(1) 40 CFR 60.100a
(2) 40 CFR 60.101a
(3) 40 CFR 60.102a(a)
(4) 40 CFR 60.102a(f)(1)
(5) 40 CFR 60.102a(g)
(6) 40 CFR 60.103a(a)
(7) 40 CFR 60.103a(b)
(8) 40 CFR 60.103a(c)
(9) 40 CFR 60.103a(d)
(10) 40 CFR 60.103a(e)
(11) 40 CFR 60.103a(h)
(12) 40 CFR 60.103a(j)
(13) 40 CFR 60.104a(a)
(14) 40 CFR 60.104a(c)
(15) 40 CFR 60.104a(h)
(16) 40 CFR 60.104a(i)
(17) 40 CFR 60.104a(j)
(18) 40 CFR 60.106a
(19) 40 CFR 60.107a(a)
(20) 40 CFR 60.107a(b)

(21) 40 CFR 60.107a(c)
(22) 40 CFR 60.107a(d)
(23) 40 CFR 60.107a(e)
(24) 40 CFR 60.107a(f)
(25) 40 CFR 60.107a(g)
(26) 40 CFR 60.107a(i)
(27) 40 CFR 60.108a
(28) 40 CFR 60.109a

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart Ja.

(i) The requirements of the Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, 40 CFR 60, Subpart K and 326 IAC 12, are not included in the permit for the storage vessels listed in paragraph (k), because the units commenced construction after May 19, 1978.

(j) The requirements of the Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984, 40 CFR 60, Subpart Ka and 326 IAC 12, are not included in the permit for the storage vessels listed in paragraph (k), because the units commenced construction after July 23, 1984.

(k) This source is subject to the Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, 40 CFR 60, Subpart Kb and 326 IAC 12, because construction of the storage vessels commenced after July 23, 1984. Applicability of this subpart to each storage vessel is discussed in the table below:

ID	Contents	Capacity (gallons) (m^3)	Subject	Not Subject	Reason Not Subject
T1	Naphtha product	4,629,879 (17,524)	X		
T2	Naphtha product	4,629,879 (17,524)	X		
T3	Diesel product	4,629,879 (17,524)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T4	Diesel product	4,629,879 (17,524)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T5	Diesel product	4,629,879 (17,524)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T6	Naphtha or diesel product	4,629,879 (17,524)	X		
T7	Molten sulfur	346,367 (1,311)		X	contents not volatile organic liquid (40 CFR 60.111b)
T8	Molten sulfur	346,367 (1,311)		X	contents not volatile organic liquid (40 CFR 60.111b)
T9	Ammonia product (pressurized)	36,720 (17,524)		X	pressure vessel (40 CFR 60.110b(c)(2))

ID	Contents	Capacity (gallons) (m^3)	Subject	Not Subject	Reason Not Subject
T10	Residue surge tank 1	926,980 (17,524)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T11	Residue surge tank 2	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T12	Residue feed tank	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T13	VGO tank 1	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T14	VGO tank 2	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T15	LPG storage (pressurized)	48,872 (185)		X	pressure vessel (40 CFR 60.110b(c)(2))
T16	Slop tank	4,195,581 (15,880)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T17	Diesel fuel tank	23,775 (90)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T18	Non-phenolic sour water storage tank 1	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T19	Non-phenolic sour water storage tank 2	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T20	Non-phenolic sour water storage tank 3	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T21	Phenolic sour water storage tank	40,947 (155)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T22	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T23	Stripped phenolic sour water surge tank	13,737 (52)		X	Capacity less than 75 m^3 (40 CFR 60.110b(a)
T24	Amine surge/deinventory tank	63,943 (242)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T25	Fresh amine tank	63,943 (242)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T26	Amine containment tank	793 (3)		X	Capacity less than 75 m^3 (40 CFR 60.110b(a)

Tanks T1, T2, and T6 are subject to the following portions of Subpart Kb.

(1) 40 CFR 60.110b(a)

(2) 40 CFR 60.110b(e)
(3) 40 CFR 60.111b
(4) 40 CFR 60.112b(a)(1)
(5) 40 CFR 60.113b(a)
(6) 40 CFR 60.114b
(7) 40 CFR 60.115b(a)
(8) 40 CFR 60.116b
(9) 40 CFR 60.117b

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to tanks T1, T2, and T6 except as otherwise specified in 40 CFR 60, Subpart Kb.

(l) Block 1000 is subject to the Standards of Performance for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y and 326 IAC 12, because Block 1000 is a coal preparation and processing plant as defined at 40 CFR 60.251(e) that commenced construction after May 27, 2009. The units subject to this rule include the following:

- Coal handling operations, identified as Block 1000, consisting of:

(1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

(A) Two (2) unloading chutes, identified as Unloading Chute 1 and Unloading Chute 2, discharging to Unloading Hopper 1 and Unloading Hopper 2, respectively.
(B) Two (2) unloading hoppers, identified as Unloading Hopper 1 and Unloading Hopper 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively.
(C) Two (2) drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to Conveyor 1.

(2) One (1) enclosed rail unloading conveyor discharging to the Conveyor 1 Transfer Station, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

(3) One (1) enclosed transfer station discharging to Conveyor 2, Conveyor 3, or Conveyor 9, identified as EU-1001, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor 2A, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(5) One (1) enclosed stacker boom conveyor discharging to the Stockpile #1 & #2 Discharge Chute, identified as EU-1002, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity

of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1 and Stockpile #2, with a maximum capacity of 93,000 tons, controlled by a total enclosure.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor 3A, identified as Conveyor 3, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(8) One (1) enclosed stacker boom conveyor discharging to the Stockpile #3 & #4 Discharge Chute, identified as Stacker 2 Boom Conveyor 3A, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #3 and Stockpile #4, with a maximum capacity of 93,000 tons, controlled by a total enclosure.

(10) One (1) reclaimer for Stockpiles #1 & #2, discharging to Reclaimer 1 Conveyor 4, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions by the stockpile #1and #2 enclosure.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 4 discharging to the Reclaim Transfer Structure, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(12) One (1) reclaimer for Stockpiles #3 & #4, discharging to Reclaimer 2 Conveyor 5, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by the stockpile #3 and #4 enclosure.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 5 discharging to the Reclaim Transfer Structure, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Structure, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(15) One (1) enclosed reclaim transfer structure discharging to Reclaim Transfer Conveyor 6, identified as EU-1006, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(16) One (1) enclosed raw coal bunker, identified as T32, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(17) One (1) enclosed coal mill conveyor, identified as Conveyor 6 discharging to the Coal Mill & Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by what, exhausting to where.

(18) One (1) enclosed coal mill and pulverizer discharging to the Coal Dryer, identified as Coal Mill & Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(19) One (1) enclosed coal dryer discharging to the Pulverized Coal Baghouse, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(21) One (1) baghouse discharging to the Coal Hopper, identified as Pulverized Coal Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) hopper receiving coal from Block 1000 and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

(2) One (1) enclosed screw conveyor discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,260,080 tons per year, with emissions controlled by what, exhausting to where.

The units are subject to the following portions of Subpart Y.

(1) 40 CFR 60.250(a)
(2) 40 CFR 60.250(d)
(3) 40 CFR 60.251
(4) 40 CFR 60.252(b)(1)
(5) 40 CFR 60.252(b)(2)
(6) 40 CFR 60.252(b)(3)
(7) 40 CFR 60.252(c)
(8) 40 CFR 60.254(b)
(9) 40 CFR 60.255(b)
(10) 40 CFR 60.255(c)
(11) 40 CFR 60.255(d)
(12) 40 CFR 60.255(e)
(13) 40 CFR 60.255(f)
(14) 40 CFR 60.255(g)
(15) 40 CFR 60.256(b)

(16) 40 CFR 60.256(c)
(17) 40 CFR 60.257
(18) 40 CFR 60.258

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the units except as otherwise specified in 40 CFR 60, Subpart Y.

(m) The requirements of the Standards of Performance for Metallic Mineral Processing Plants, 40 CFR 60, Subpart LL and 326 IAC 12, are not included in the permit for Block 1500 additive handling and storage operations, the Block 2000 additive preparation operations, or the Block 6500 lime handling and storage operations because the operations are not a metallic mineral processing plant as defined at 40 CFR 60.381. The operations do not produce metallic mineral concentrates from ores.

(n) The requirements of the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006, 40 CFR 60, Subpart VV and 326 IAC 12, are not included in the permit for the source, because the source commenced construction after November 7, 2006.

(o) The requirements of the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart VVa and 326 IAC 12, are not included in the permit for the source, because the source is not in the synthetic organic chemical manufacturing industry as defined at 40 CFR 60.481a. The source does not produce, as an intermediate or final product, one or more of the chemicals listed in 40 CFR 60.489.

(p) The requirements of the Standards of Performance for Bulk Gasoline Terminals, 40 CFR 60, Subpart XX and 326 IAC 12, are not included in the permit for the Product Loading Rack, because the source is not a bulk gasoline terminal as defined at 40 CFR 60.501. The source does not receive gasoline by pipeline, ship, or barge.

(q) The requirements of the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006, 40 CFR 60, Subpart GGG and 326 IAC 12, are not included in the permit for this source, because the source commenced construction after November 7, 2006.

(r) This source is subject to the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart GGGa and 326 IAC 12, because the source is a facility engaged in producing distillate fuel oils or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. As defined at 40 CFR 60.591a, *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal. The facilities subject to this rule include the group of all the equipment (defined in § 60.591a) within each of the following process units:

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

  (3) One (1) nitrogen-blanketed Na_2S slurry preparation system discharging to the Block 2000 feed premix drum, identified as Na_2S Slurry Preparation, approved in 2018 for construction, consisting of:

    (C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil)

(6) One (1) feed premix drum receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, identified as Feed Premix Drum, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater discharging to the 1st stage reactors, identified as EU-2001, approved in 2018 for construction, with a maximum heat input capacity of 128.4 MMBtu/hr, using no add-on controls and exhausting to stack EU-2001.

(9) One (1) first stage reactor - liquid phase hydrocracking system discharging to the hot separator, identified as LPH, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(10) One (1) hot separator discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, identified as Hot Separator, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater discharging to the vacuum distillation tower, identified as EU-2003, approved in 2018 for construction, with a maximum heat input capacity of 9 MMBtu/hr, using no add on controls and exhausting to stack EU-2003

(12) One (1) vacuum distillation tower discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 8000(?), phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, identified as Vacuum Distillation Column, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(13) One (1) second stage reactor - gas phase hydrotreating system discharging to the cold separator, identified as GPH, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(14) One (1) cold separator discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, identified as Cold Separator, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater discharging to the fractionator tower, identified as EU-2004, approved in 2018 for construction, with a maximum heat input capacity of 156 MMBtu/hr, using no add on controls and exhausting to stack EU-2004.

(16) One (1) fractionator tower discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, identified as Fractionator Tower, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, identified as HP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, identified as LP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) stripper column discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger or the reboiler and vapor to the overheads condenser, identified as Stripper, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser discharging condensate to the stripper condenser accumulator, identified as Overheads Condenser, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(D) One (1) accumulator drum discharging condensate to stripper reflux or the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, identified as Stripper Condenser Accumulator, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler discharging lean amine to the stripper reflux, identified as Stripper Reboiler, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system receiving sour water from the Block 2000 vacuum distillation column, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602A burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602A Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605A, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUA

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602B burner, discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602B furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602B Waste Heat Boiler.

(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605B, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUB

- Offsite operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) flare servicing overpressure and emergency reliefs from Block 2000, identified as High Pressure (HP) Flare, approved in 2018 for construction.

(B) One (1) flare servicing overpressure reliefs from Block 7000, identified as Low Pressure (LP) Flare, approved in 2018 for construction.

(C) One (1) flare servicing overpressure reliefs from Block 3000 and sulfur loading, identified as Sulfur Block Flare, approved in 2018 for construction.

(D) One (1) flare servicing Block 4000 naphtha, diesel, and ammonia loading operations, identified as Loading Flare, approved in 2018 for construction.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T1	IFR	Naphtha product	4,629,879 (17,524)
T2	IFR	Naphtha product	4,629,879 (17,524)
T3	FR	Diesel product	4,629,879 (17,524)
T4	FR	Diesel product	4,629,879 (17,524)
T5	FR	Diesel product	4,629,879 (17,524)
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)
T10	FR	Residue surge tank 1	926,980 (17,524)
T11	FR	Residue surge tank 2	926,980 (3,509)
T12	FR	Residue feed tank	926,980 (3,509)
T13	FR	VGO tank 1	926,980 (3,509)
T14	FR	VGO tank 2	926,980 (3,509)
T15	FR	LPG storage (pressurized)	48,872 (185)

Notes:
1. FR - fixed roof, IFR - internal floating roof

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart EEEE, the Product Loading Rack is an affected source.

- Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide absorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer fired with Block 2000 off-gas and PSA tail gas supplemented by natural gas and process fuel gas and discharging water gas to the CO-shift converter, identified as EU-7003, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr, using selective catalytic reduction for NOx control and exhausting combustion products to the waste heat recovery boiler.

(ii) One (1) heat recovery boiler, identified as Heat Recovery Boiler 1, approved in 2018 for construction, using no controls and exhausting to stack EU-7003.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(2) Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide absorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer fired with Block 2000 off-gas and PSA tail gas supplemented by natural gas and process fuel gas and discharging water gas to the CO-shift converter, identified as EU-7004, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr, using selective catalytic reduction for NOx control and exhausting combustion products to the waste heat recovery boiler.

(ii) One (1) heat recovery boiler, identified as Heat Recovery Boiler 2, approved in 2018 for construction, using no controls and exhausting to stack EU-7004.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

Note: Pursuant to 40 CFR 60.590a(e), owners or operators are not required to comply with the definition of "process unit" in § 60.591 of this subpart until the EPA takes final action to require compliance and publishes a document in the Federal Register. While the definition of "process unit" is stayed, owners or operators should use the following definition:

> *Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

This exclusion affects storage vessels, product transfer racks, and connected ducts and piping.

This source is subject to the following portions of Subpart GGGa.

(1) 40 CFR 60.590a
(2) 40 CFR 60.591a
(3) 40 CFR 60.592a
(4) 40 CFR 60.593a

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart GGGa.

(s) The vacuum distillation tower and fractionator tower are subject to the Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations, 40 CFR 60, Subpart NNN and 326 IAC 12, because the units are part of a process unit that produces one or more of the chemicals listed in 40 CFR 60.667 as a product, co-product, byproduct, or intermediate. The units subject to this rule include the following:

- One (1) vacuum distillation tower discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 8000(?), phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, identified as Vacuum Distillation Column, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

- One (1) fractionator tower discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, identified as Fractionator Tower, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

The vacuum distillation tower and fractionator tower are subject to the following portions of Subpart NNN.

(1) 40 CFR 60.660(a)
(2) 40 CFR 60.660(b)(3)
(3) 40 CFR 60.660(c)(4)
(4) 40 CFR 60.661
(5) 40 CFR 60.662
(6) 40 CFR 60.663(f)
(7) 40 CFR 60.664
(8) 40 CFR 60.665
(9) 40 CFR 60.666
(10) 40 CFR 60.667
(11) 40 CFR 60.668

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the vacuum distillation tower and fractionator tower except as otherwise specified in 40 CFR 60, Subpart NNN.

(y) 40 CFR 60, Subpart OOO

(1) The requirements of the Standards of Performance for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the enclosed coal mill and pulverizer, because coal is not a nonmetallic mineral as defined at 40 CFR 60.671.

(2) The requirements of the Standards of Performance for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the operations listed in the table below, because the units are not nonmetallic mineral processing plants as defined at 40 CFR 60.671. The units are not equipment that is used to crush or grind any nonmetallic mineral as defined at 40 CFR 60.671.

Units Not Subject to Subpart OOO
Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, identified as Sodium Sulfide (Na_2S) Unloading, Fine Additive Unloading, and Coarse Additive Unloading
One (1) Na_2S silo, identified as T35
One (1) fine additive silo, identified as T33
One (1) coarse additive silo
One (1) enclosed screw conveyor discharging to the Feed Premix Drum, identified as Closed Screw Conveyor
One (1) nitrogen-blanketed Na_2S slurry preparation system
One (1) nitrogen-blanketed fine additive transfer system discharging to the Block 2000 feed premix drum, identified as Fine Additive Transfer
One (1) feed premix drum receiving coal, solid additives, and recycled vacuum gas oil (VGO)
Block 6500 pneumatic lime truck unloading system
One (1) lime storage silo, identified as EU-6501

(3) The requirements of the Standards of Performance for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the Block 1500 fine additive production system, because the unit is not a nonmetallic mineral processing plant as defined at 40 CFR 60.671. The unit does not crush or grind any nonmetallic mineral listed in 40 CFR 60.671 or a mixture of which the majority is any of the listed minerals. The solid additive is predominantly a byproduct of bauxite processing commonly known as red mud.

(u) This source is subject to the Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR 60, Subpart QQQ and 326 IAC 12, because the source is a petroleum refinery for which construction commenced after May 4, 1987. The units subject to this rule include the following:

- Affected facilities in petroleum refineries, including the following as defined at 40 CFR 60.691:

    (1) Each individual drain system
    (2) Each oil-water separator
    (3) Each aggregate facility

This source is subject to the following portions of Subpart QQQ.

(1) 40 CFR 60.690
(2) 40 CFR 60.691
(3) 40 CFR 60.692-1
(4) 40 CFR 60.692-2
(5) 40 CFR 60.692-3
(6) 40 CFR 60.692-4
(7) 40 CFR 60.692-5
(8) 40 CFR 60.692-6
(9) 40 CFR 60.692-7
(10) 40 CFR 60.693-1

(11) 40 CFR 60.693-2
(12) 40 CFR 60.694
(13) 40 CFR 60.695
(14) 40 CFR 60.696
(15) 40 CFR 60.697
(16) 40 CFR 60.698
(17) 40 CFR 60.699

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart QQQ.

(v) The first stage reactor - liquid phase hydrocracking system and second stage reactor - gas phase hydrotreating system are subject to the Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes, 40 CFR 60, Subpart RRR and 326 IAC 12, because the units are reactor processes that are part of a process unit that that produces one or more of the chemicals listed in 40 CFR 60.707 as a product, co-product, byproduct, or intermediate. The units subject to this rule include the following:

- One (1) first stage reactor - liquid phase hydrocracking system discharging to the hot separator, identified as LPH, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

- One (1) second stage reactor - gas phase hydrotreating system discharging to the cold separator, identified as GPH, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

The first stage reactor - liquid phase hydrocracking system and second stage reactor - gas phase hydrotreating system are subject to the following portions of Subpart RRR.

(1) 40 CFR 60.700(a)
(2) 40 CFR 60.700(b)(3)
(3) 40 CFR 60.700(c)(5)
(4) 40 CFR 60.701
(5) 40 CFR 60.705(r)
(6) 40 CFR 60.706
(7) 40 CFR 60.707
(8) 40 CFR 60.708

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the first stage reactor - liquid phase hydrocracking system and second stage reactor - gas phase hydrotreating system except as otherwise specified in 40 CFR 60, Subpart RRR.

(w) The emergency generator and emergency fire pump are subject to the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because the units are stationary compression ignition internal combustion engines that commenced construction after July 11, 2005.

Based on this evaluation, this source is subject to 40 CFR 60, Subpart IIII. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 60.4211(f)(2)(ii) - (iii) of NSPS Subpart IIII. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo: [HYPERLINK "https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf"]

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 60.4211(f)(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraph~~s~~ (f)(2)(i) ~~through (iii)~~ of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.~~

~~(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.~~

The units subject to this rule include the following:

- One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 17.86 MMBtu/hr (2,800 hp), using no add-on controls and exhausting to stack EU-6006.

- One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.14 MMBtu/hr (750 hp), using no add-on controls and exhausting to stack EU-6008.

The units are subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)
(2) 40 CFR 60.4200(a)(4)
(3) 40 CFR 60.4205(b)
(4) 40 CFR 60.4205(c)
(5) 40 CFR 60.4206
(6) 40 CFR 60.4207(b)
(7) 40 CFR 60.4208(a)
(8) 40 CFR 60.4209(a)
(9) 40 CFR 60.4211(a)

(10) 40 CFR 60.4211(c)
(11) 40 CFR 60.4211(f)(1)
(12) 40 CFR 60.4211(f)(2)(i)
(13) 40 CFR 60.4211(f)(3)
(14) 40 CFR 60.4211(g)(2)
(15) 40 CFR 60.4211(g)(3)
(16) 40 CFR 60.4214(b)
(17) 40 CFR 60.4218
(18) 40 CFR 60.4219
(19) Table 4 to Subpart IIII of Part 60
(20) Table 5 to Subpart IIII of Part 60
(21) Table 8 to Subpart IIII of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the emergency generator and emergency fire pump except as otherwise specified in 40 CFR 60, Subpart IIII.

(x) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit for this proposed new source.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The loading rack, EU-4007 is subject to the National Emission Standard for Benzene Emissions From Benzene Transfer Operations, 40 CFR 61, Subpart BB, because the unit is a loading rack at which benzene is loaded into railcars. Based on information provided by the licensor, the benzene content of product naphtha is expected to be 0.9% by weight. The units subject to this rule include the following:

- One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

The Product Loading Rack is subject to the following portions of Subpart BB:

(1) 40 CFR 61.300(a)
(2) 40 CFR 61.300(b)
(3) 40 CFR 61.304(i)

(b) This source is subject to the National Emission Standards for Benzene Waste Operations, 40 CFR 61, Subpart FF, because the source is a petroleum refinery as defined in 40 CFR 61.341. The units subject to this rule include the following:

Not well defined at this time (6/26/18). Excludes (§340(c)) gas or vapor emitted from process fluids and segregated wastewater. Also excludes (§340(d)) gases directed to fuel gas system. That seems to leave wastewater streams

This source is subject to the following portions of Subpart FF:

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.343
(4) 40 CFR 61.346
(5) 40 CFR 61.347
(6) 40 CFR 61.348
(7) 40 CFR 61.349

(8) 40 CFR 61.350
(9) 40 CFR 61.351
(10) 40 CFR 61.352
(11) 40 CFR 61.353
(12) 40 CFR 61.354
(13) 40 CFR 61.355
(14) 40 CFR 61.356
(15) 40 CFR 61.357
(16) 40 CFR 61.358

The requirements of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated as 326 IAC 14-1, apply to the source except as otherwise specified in 40 CFR 61, Subpart FF.

(c) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From the Synthetic Organic Chemical Manufacturing Industry, 40 CFR 63, Subpart F and 326 IAC 20-11 are not included in the permit for this source, since the source does not manufacture as a primary product one or more of the chemicals listed in 40 CFR 63.100(b)(1)(i) or(ii).

(d) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater, 40 CFR 63, Subpart G and 326 IAC 20-11 are not included in the permit for this source, since the source is not subject to 40 CFR 63, Subpart F.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From the Synthetic Organic Chemical Manufacturing Industry for Equipment Leaks, 40 CFR 63, Subpart H, 326 IAC 20-11, and 326 IAC 20-12 are not included in the permit. The source is not subject to provisions of 40 CFR 63, Subpart CC that reference this subpart. Pursuant to 40 CFR 63.640(p)(2), equipment leaks subject to 40 CFR 63, Subpart CC that are also subject to 40 CFR 60, Subpart GGGa are required to comply only with the provisions specified in 40 CFR 60, Subpart GGGa.

(f) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Process Cooling Towers, 40 CFR 63, Subpart Q and 326 IAC 20-4 are not included in the permit for the cooling tower (EU-6001, EU-6002, and EU-6003), since the cooling towers are not operated with chromium-based water treatment chemicals.

(g) The requirements of the National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), 40 CFR 63, Subpart R and 326 IAC 20-10 are not included in the permit for the source, since the source is not a bulk gasoline terminal or a pipeline breakout station. The source does not receive gasoline by pipeline, ship or barge. The source is not a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

(h) The requirements of the National Emission Standards for Marine Tank Vessel Loading Operations, 40 CFR 63, Subpart Y and 326 IAC 20-17 are not included in the permit for the source, since the source is not a marine tank vessel loading operation as defined at 40 CFR 63.561.

(i) This source is subject to the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, 40 CFR 63, Subpart CC and 326 IAC 20-16, because the units are petroleum refining process units as defined at 40 CFR 63.641. The units subject to this rule include the following:

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(3) One (1) nitrogen-blanketed Na_2S slurry preparation system discharging to the Block 2000 feed premix drum, identified as Na_2S Slurry Preparation, approved in 2018 for construction, consisting of:

(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil)

(6) One (1) feed premix drum receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, identified as Feed Premix Drum, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater discharging to the 1st stage reactors, identified as EU-2001, approved in 2018 for construction, with a maximum heat input capacity of 128.4 MMBtu/hr, using no add-on controls and exhausting to stack EU-2001.

(9) One (1) first stage reactor - liquid phase hydrocracking system discharging to the hot separator, identified as LPH, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(10) One (1) hot separator discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, identified as Hot Separator, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater discharging to the vacuum distillation tower, identified as EU-2003, approved in 2018 for construction, with a maximum heat input capacity of 9 MMBtu/hr, using no add on controls and exhausting to stack EU-2003

(12) One (1) vacuum distillation tower discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 8000(?), phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, identified as Vacuum Distillation Column, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(13) One (1) second stage reactor - gas phase hydrotreating system discharging to the cold separator, identified as GPH, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(14) One (1) cold separator discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, identified as Cold Separator, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater discharging to the fractionator tower, identified as EU-2004, approved in 2018 for construction, with a maximum heat input capacity of 156 MMBtu/hr, using no add on controls and exhausting to stack EU-2004.

(16) One (1) fractionator tower discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, identified as Fractionator Tower, approved in 2018 for construction, using no controls and discharging emergency and pressure relief streams to the Block 4000 high pressure flare.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, identified as HP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, identified as LP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) stripper column discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger or the reboiler and vapor to the overheads condenser, identified as Stripper, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser discharging condensate to the stripper condenser accumulator, identified as Overheads Condenser, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(D) One (1) accumulator drum discharging condensate to stripper reflux or the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, identified as Stripper Condenser Accumulator, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler discharging lean amine to the stripper reflux, identified as Stripper Reboiler, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block

4000 sulfur flare.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system receiving sour water from the Block 2000 vacuum distillation column, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602A burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602A Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605A, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUA

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602B burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602B Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605B, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUB

- Offsite operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) flare servicing overpressure and emergency reliefs from Block 2000, identified as High Pressure (HP) Flare, approved in 2018 for construction.

(B) One (1) flare servicing overpressure reliefs from Block 7000, identified as Low Pressure (LP) Flare, approved in 2018 for construction.

(C) One (1) flare servicing overpressure reliefs from Block 3000 and sulfur loading, identified as Sulfur Block Flare, approved in 2018 for construction.

(D) One (1) flare servicing Block 4000 naphtha, diesel, and ammonia loading operations, identified as Loading Flare, approved in 2018 for construction.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T1	IFR	Naphtha product	4,629,879 (17,524)
T2	IFR	Naphtha product	4,629,879 (17,524)
T3	FR	Diesel product	4,629,879 (17,524)
T4	FR	Diesel product	4,629,879 (17,524)
T5	FR	Diesel product	4,629,879 (17,524)
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)
T10	FR	Residue surge tank 1	926,980 (17,524)
T11	FR	Residue surge tank 2	926,980 (3,509)
T12	FR	Residue feed tank	926,980 (3,509)
T13	FR	VGO tank 1	926,980 (3,509)
T14	FR	VGO tank 2	926,980 (3,509)
T15	FR	LPG storage (pressurized)	48,872 (185)

Notes:
1. FR - fixed roof, IFR - internal floating roof

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

- Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer fired with Block 2000 off-gas and PSA tail gas supplemented by natural gas and process fuel gas and discharging water gas to the CO-shift converter, identified as EU-7003, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr, using selective catalytic reduction for NOx control and exhausting combustion products to the waste heat recovery boiler.

(ii) One (1) heat recovery boiler, identified as Heat Recovery Boiler 1, approved in 2018 for construction, using no controls and exhausting to stack EU-7003.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(2) Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer fired with Block 2000 off-gas and PSA tail gas supplemented by natural gas and process fuel gas and discharging water gas to the CO-shift converter, identified as EU-7004, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr, using selective catalytic reduction for NOx control and exhausting combustion products to the waste heat recovery boiler.

(ii) One (1) heat recovery boiler, identified as Heat Recovery Boiler 2, approved in 2018 for construction, using no controls and exhausting to stack EU-7004.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

The units are subject to the following portions of Subpart CC:

(1) 40 CFR 63.640(a)
(2) 40 CFR 63.640(c)
(3) 40 CFR 63.640(d)
(4) 40 CFR 63.640(e)
(5) 40 CFR 63.640(f)
(6) 40 CFR 63.640(h)
(7) 40 CFR 63.640(k)
(8) 40 CFR 63.640(m)
(9) 40 CFR 63.640(n)(2)
(10) 40 CFR 63.640(n)(8)
(11) 40 CFR 63.640(o)(1)
(12) 40 CFR 63.640(p)(2)

(13) 40 CFR 63.641
(14) 40 CFR 63.642
(15) 40 CFR 63.643
(16) 40 CFR 63.644
(17) 40 CFR 63.645
(18) 40 CFR 63.647
(19) 40 CFR 63.654
(20) 40 CFR 63.655
(21) 40 CFR 63.656
(22) 40 CFR 63.658
(23) Table 11 to Subpart CC of Part 60

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart CC.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From Oil and Natural Gas Production Facilities, 40 CFR 63, Subpart HH and 326 IAC 20-30 are not included in the permit for this source, since the source does not process, upgrade, or store natural gas and does not process, upgrade, or store hydrocarbon liquids as defined at 40 CFR 63.761. The liquids processed and stored at the source are not naturally occurring, unrefined petroleum liquids.

(k) The requirements of the National Emission Standards for Tanks—Level 1, 40 CFR 63, Subpart OO and 326 IAC 20-35 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(l) The requirements of the National Emission Standards for Containers, 40 CFR 63, Subpart PP and 326 IAC 20-36 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(m) The requirements of the National Emission Standards for Surface Impoundments, 40 CFR 63, Subpart QQ and 326 IAC 20-37 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(n) The requirements of the National Emission Standards for Individual Drain Systems, 40 CFR 63, Subpart RR and 326 IAC 20-38 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(o) The requirements of the National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process, 40 CFR 63, Subpart SS and 326 IAC 20-39 are not included in the permit for this source. Pursuant to 40 CFR 63.640(n)(2), Group 1 storage vessels subject to 40 CFR 63, Subpart CC that are also subject to 40 CFR 60, Subpart Kb is required to comply with either 40 CFR part 60, subpart Kb, except as provided in 40 CFR 63.640(n)(8) or with 40 CFR 63, Subpart CC. This source will comply with 40 CFR 60, Subpart Kb, therefore the source is not subject to provisions of 40 CFR 63, Subpart CC that reference this subpart.

(p) The requirements of the National Emission Standards for Equipment Leaks - Control Level 1, 40 CFR 63, Subpart TT and 326 IAC 20-40 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(q) The requirements of the National Emission Standards for Equipment Leaks - Control Level 2 Standards, 40 CFR 63, Subpart UU and 326 IAC 20-41 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(r) The requirements of the National Emission Standards for Oil-Water Separators and Organic-Water Separators, 40 CFR 63, Subpart VV and 326 IAC 20-42 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(s) This source is subject to the National Emission Standards for Storage Vessels (Tanks) - Control Level 2, 40 CFR 63, Subpart WW and 326 IAC 20-43, because the source is subject to Subpart CC, which references this subpart. The units subject to this rule include the following:

- Offsite operations, identified as Block 4000, consisting of:

  (2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T1	IFR	Naphtha product	4,629,879 (17,524)
T2	IFR	Naphtha product	4,629,879 (17,524)
T3	FR	Diesel product	4,629,879 (17,524)
T4	FR	Diesel product	4,629,879 (17,524)
T5	FR	Diesel product	4,629,879 (17,524)
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)
T10	FR	Residue surge tank 1	926,980 (17,524)
T11	FR	Residue surge tank 2	926,980 (3,509)
T12	FR	Residue feed tank	926,980 (3,509)
T13	FR	VGO tank 1	926,980 (3,509)
T14	FR	VGO tank 2	926,980 (3,509)
T15	FR	LPG storage (pressurized)	48,872 (185)

These units are subject to the following portions of Subpart WW:

(1) 40 CFR 63.1060
(2) 40 CFR 63.1061
(3) 40 CFR 63.1063(c)(2)(iv)(A)
(4) 40 CFR 63.1063(c)(2)(iv)(B)
(5) 40 CFR 63.1065(a)
(6) 40 CFR 63.1067

(a) 40 CFR 63.1063(c)(1)
(b) 40 CFR 63.1063(d)(1)
(c) 40 CFR 63.1063(d)(2)
(d) 40 CFR 63.1065(b)

(e) 40 CFR 63.1063(e)(2)

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, do not apply to this subpart except as specified in a referencing subpart.

(s) The requirements of the National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations, 40 CFR 63, Subpart XX are not included in the permit for this source, since the source does not operate an ethylene production unit or an ethylene production facility referenced to this subpart by subpart YY.

(t) The requirements of the National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards, 40 CFR 63, Subpart YY and 326 IAC 20-44 are not included in the permit for this source, since the source does not operate an ethylene production unit as defined at 40 CFR 63.1103(e)(2).

(u) This source is subject to the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, 40 CFR 63, Subpart UUU and 326 IAC 20-50, because the source is a petroleum refinery located at a major source of HAP emissions.

The process vents and bypass lines serving the liquid phase hydrocracking (LPH) operation, gas phase hydrotreating (GPH) operation, and hydrogen production plant are not affected facilities under this subpart. These operations are not fluidized catalytic crack units, catalytic reforming units, or sulfur recovery units as defined at 40 CFR 63.1579. These operations are not described by the following definitions from 40 CFR 63.1579:

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits.

Catalytic reforming unit means a refinery process unit that reforms or changes the chemical structure of naphtha into higher octane aromatics through the use of a metal catalyst and chemical reactions that include dehydrogenation, isomerization, and hydrogenolysis.

Sulfur recovery unit means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

The units subject to this rule include the following:

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

  (17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

    (A) One (1) two-stage high pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, identified as HP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, identified as LP Absorber, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) stripper column discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger or the reboiler and vapor to the overheads condenser, identified as Stripper, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser discharging condensate to the stripper condenser accumulator, identified as Overheads Condenser, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(D) One (1) accumulator drum discharging condensate to stripper reflux or the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, identified as Stripper Condenser Accumulator, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler discharging lean amine to the stripper reflux, identified as Stripper Reboiler, approved in 2018 for construction, and discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system receiving sour water from the Block 2000 vacuum distillation column, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, and discharging acid gas to the sulfur recovery system and emergency and pressure relief streams to the Block 4000 sulfur flare.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602A burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602A Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605A, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUA

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602B burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602B Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the tail gas treatment unit

(TGTU) heat exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 87,500,000 pounds of sulfur per year and a nominal capacity of 62,500,000 pounds per year, discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605B, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUB

- Offsite operations, identified as Block 4000, consisting of:

  (1) Flares, as follows:

    (C) One (1) flare servicing overpressure reliefs from Block 3000 and sulfur loading, identified as Sulfur Block Flare, approved in 2018 for construction.

This source is subject to the following portions of Subpart UUU:

(1) 40 CFR 63.1560
(2) 40 CFR 63.1561
(3) 40 CFR 63.1562(a)
(4) 40 CFR 63.1562(b)(3)
(5) 40 CFR 63.1562(b)(4)
(6) 40 CFR 63.1562(c)
(7) 40 CFR 63.1563(a)(2)
(8) 40 CFR 63.1563(f)
(9) 40 CFR 63.1568(a)(1)
(10) 40 CFR 63.1569
(11) 40 CFR 63.1570
(12) 40 CFR 63.1571
(13) 40 CFR 63.1572
(14) 40 CFR 63.1573
(15) 40 CFR 63.1574
(16) 40 CFR 63.1575
(17) 40 CFR 63.1576
(18) 40 CFR 63.1577
(19) 40 CFR 63.1578
(20) 40 CFR 63.1579
(21) Table 36 to Subpart UUU of Part 63
(22) Table 37 to Subpart UUU of Part 63
(23) Table 38 to Subpart UUU of Part 63

(24) Table 39 to Subpart UUU of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart UUU.

(v) The requirements of the National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), 40 CFR 63, Subpart EEEE and 326 IAC 20-83, are not included in the permit for this source, because, pursuant to 40 CFR 63.2338(c)(1), the storage tanks and product loading racks subject to this subpart are part of an affected source under 40 CFR 63, Subpart CC.

(w) The emergency generator and emergency fire pump are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ and 326 IAC 20-82, because the units are stationary reciprocating internal combustion engines constructed after December 19, 2002. The units subject to this rule include the following:

- One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 17.86 MMBtu/hr (2,800 hp), using no add-on controls and exhausting to stack EU-6006.

- One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.14 MMBtu/hr (750 hp), using no add-on controls and exhausting to stack EU-6008.

Based on this evaluation, this source is subject to 40 CFR 63, Subpart ZZZZ. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 63.6640(f)(2)(ii) - (iii) of NESHAP Subpart ZZZZ. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo: [HYPERLINK "https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf"]

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 63.6640(f)(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) ~~through (iii)~~ of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.~~

~~(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.~~

EU-6006 and EU-6008 are subject to the following portions of Subpart ZZZZ:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(i)
(4) 40 CFR 63.6590(b)(1)(i)
(5) 40 CFR 63.6640(f)(1)
(6) 40 CFR 63.6640(f)(2)(i)
(7) 40 CFR 63.6640(f)(3)
(8) 40 CFR 63.6645(f)
(9) 40 CFR 63.6665
(10) 40 CFR 63.6670
(11) 40 CFR 63.6675
(12) Table 8 to Subpart ZZZZ of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to EU-6006 and EU-6008 except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(x) This source is subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD and 326 IAC 20-95, because the source owns or operates industrial, commercial, or institutional boilers or process heaters as defined in §63.7575 that are located at, or are part of, a major source of HAP.

The natural gas and process fuel gas-fired heater, identified as EU-1007, is not subject to 40 CFR 63, Subpart DDDDD because this unit is not a boiler or process heater as defined at 40 CFR 63.7575. The unit is direct fired and does not heat steam or water or transfer heat indirectly to a process material or heat transfer material.

The components of Sulfur Recovery Units A and B listed below are not boilers as defined at 40 CFR 63.7575. The units do not have a primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from the definition of "boiler" at 40 CFR 63.7575. The components of Sulfur Recovery Units A and B are not process heaters as defined at 40 CFR 63.7575. The units do not transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Except for the waste heat boilers, the units either heat process materials directly or are reactors that use or release thermal energy.

- One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602A burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602A Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605A, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUA

- One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner combusting acid gas from the sour water stripper using natural gas and process fuel gas for start-up, identified as A-602B burner, discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler discharging cooled gas to the Claus reactors and high pressure steam to Block 6000, identified as A-602B Waste Heat Boiler.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the tail gas treatment unit (TGTU) heat exchanger and molten sulfur to the sulfur product pit.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(x) One (1) incinerator combusting tail gas and natural gas and process fuel gas, identified as A-605B, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas), exhausting to stack TGTUB

The components of Hydrogen Plants 1 and 2 listed below are not boilers as defined at 40 CFR 63.7575. The units do not have a primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from the definition of "boiler" at 40 CFR 63.7575. The components of Hydrogen Plants 1 and 2 are not process heaters as defined at 40 CFR 63.7575. The units do not transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Except for the waste heat boilers, the units either heat process materials directly or are reactors that use or release thermal energy.

- Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer fired with Block 2000 off-gas and PSA tail gas supplemented by natural gas and process fuel gas and discharging water gas to the CO-shift converter, identified as EU-7003, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr, using selective catalytic reduction for NOx control and exhausting combustion products to the waste heat recovery boiler.

(ii) One (1) heat recovery boiler, identified as Heat Recovery Boiler 1, approved in 2018 for construction, using no controls and exhausting to stack EU-7003.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

- Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer fired with Block 2000 off-gas and PSA tail gas supplemented by natural gas and process fuel gas and discharging water gas to the CO-shift converter, identified as EU-7004, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr, using selective catalytic reduction for NOx control and exhausting combustion products to the waste heat recovery boiler.

(ii) One (1) heat recovery boiler, identified as Heat Recovery Boiler 2, approved in 2018 for construction, using no controls and exhausting to stack EU-7004.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired indirect feed heater discharging to the 1st stage reactors, identified as EU-2001, approved in 2018 for construction, with a maximum heat input capacity of 128.4 MMBtu/hr, using no add-on controls and exhausting to stack EU-2001.

- One (1) natural gas and process fuel gas-fired indirect treat gas heater receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, identified as EU-

2002, approved in 2018 for construction, with a maximum heat input capacity of 52.8 MMBtu/hr, using no add-on controls and exhausting to stack EU-2002

- One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater discharging to the vacuum distillation tower, identified as EU-2003, approved in 2018 for construction, with a maximum heat input capacity of 9 MMBtu/hr, using no add on controls and exhausting to stack EU-2003

- One (1) natural gas and process fuel gas-fired indirect fractionator heater discharging to the fractionator tower, identified as EU-2004, approved in 2018 for construction, with a maximum heat input capacity of 156 MMBtu/hr, using no add on controls and exhausting to stack EU-2004.

- One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, with a maximum heat input capacity of 68.50 MMBtu/hr, using no add-on controls and exhausting to stack EU-6000.

This source is subject to the following portions of Subpart DDDDD:

(1) 40 CFR 63.7480
(2) 40 CFR 63.7485
(3) 40 CFR 63.7490(a)(2)
(4) 40 CFR 63.7490(b)
(5) 40 CFR 63.7495(a)
(6) 40 CFR 63.7495(d)
(7) 40 CFR 63.7495(i)
(8) 40 CFR 63.7499(l)
(9) 40 CFR 63.7500(a)(1)
(10) 40 CFR 63.7500(a)(3)
(11) 40 CFR 63.7500(b)
(12) 40 CFR 63.7500(e)
(13) 40 CFR 63.7500(f)
(14) 40 CFR 63.7505(a)
(15) 40 CFR 63.7510(g)
(16) 40 CFR 63.7510(k)
(17) 40 CFR 63.7515(d)
(18) 40 CFR 63.7515(g)
(19) 40 CFR 63.7521(f)(1)
(20) 40 CFR 63.7530(f)
(21) 40 CFR 63.7540(a)(10)
(22) 40 CFR 63.7540(a)(11)
(23) 40 CFR 63.7540(a)(12)
(24) 40 CFR 63.7540(a)(13)
(25) 40 CFR 63.7540(b)
(26) 40 CFR 63.7540(d)
(27) 40 CFR 63.7545(a)
(28) 40 CFR 63.7545(c)
(29) 40 CFR 63.7545(e)
(30) 40 CFR 63.7545(h)
(31) 40 CFR 63.7550(a)
(32) 40 CFR 63.7550(b)
(33) 40 CFR 63.7550(c)(1)
(34) 40 CFR 63.7550(h)(3)
(35) 40 CFR 63.7555(a)
(36) 40 CFR 63.7555(h)

(37) 40 CFR 63.7560
(38) 40 CFR 63.7565
(39) 40 CFR 63.7570
(40) 40 CFR 63.7575
(41) Table 3 to Subpart DDDDD of Part 63 (item 1 (continuous oxygen trim), 2 (no trim, vacuum column feed) 3 (no trim all others))
(42) Table 9 to Subpart DDDDD of Part 63
(43) Table 10 to Subpart DDDDD of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart DDDDD.

(y) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities, 40 CFR 63, Subpart BBBBBB are not included in the permit for this source, since because the source is a major source of HAP emissions

(z) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ are not included in the permit for this source, since because the source is a major source of HAP emissions

(aa) There are no other National Emission Standards for Hazardous Air Pollutants Under the NESHAP, 40 CFR 63, 326 IAC 14 and 326 IAC 20 included for this proposed new source.